BEST AVAILABLE RETROFIT TECHNOLOGY

In the Regional Haze Rule, EPA included provisions designed specifically to reduce emissions of visibility-impairing pollutants from large sources that, because of their age, were exempted from new source performance standards (NSPS) established under the Clean Air Act. These provisions, known as Best Available Retrofit Technology, or BART, are located at 40 CFR 51.308(e).

Massachusetts is required by 40 CFR §51.308(e) to submit an implementation plan containing emission limits representing BART and schedules for compliance with BART for each eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. This requirement applies unless Massachusetts demonstrates that an emission trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. Massachusetts, as a member of the MANE-VU Regional Planning Organization, has developed a strategy to meet the requirements of BART.

BART requirements apply to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns, and other large stationary sources.[1] To be considered BART-eligible, emission units from these specified categories must have commenced operation or come into existence in the 15-year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments, which first required new source performance standards). In addition, the cumulative "potential to emit" levels of all BART-eligible units at a facility must be at least 250 tons per year of any visibility-impairing pollutant.[2] Visibility-impairing pollutants include, but are not limited to, sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter less than or equal to 10 microns in diameter (PM_{10}), volatile organic chemicals (VOCs), and ammonia.

A. The BART Rule

In June 2001, EPA released proposed guidelines on BART. This guidance outlined the method for determining if a facility has a BART-eligible source, if a source is subject to BART provisions, and methods for conducting a BART control review for such sources.

In 2002, industry groups challenged the method EPA outlined in the Regional Haze Rule to determine the degree of visibility improvement resulting from application of BART controls. Under EPA's interpretation of the statute, a state would deem sources subject to BART if they emitted into a geographic area or region from which pollutants are likely transported downwind into a protected area. In May 2002, the D.C. Circuit Court of Appeals agreed with industry petitioners that this interpretation impermissibly constrained the authority of any state that

[1] A full list of the 26 source categories can be found in 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations Under the Regional Haze Rule.
[2] "Source" can refer to an emission unit or to a facility and is used in the Clean Air Act and in EPA's Guidance on Regional Haze.

wanted to provide an exemption mechanism from BART requirements. The Court vacated those portions of the Regional Haze Rule dealing with BART.

In June 2005, EPA released the final BART guidelines[3] that also addressed the remanded portions of the Regional Haze Rule dealing with BART. Under the final rule, the BART program requires states to develop an inventory of sources within each state or tribal jurisdiction that could be subject to control. Specifically, the rule:

- Outlined methods to determine if a source is "reasonably anticipated to cause or contribute to haze;"
- Defined the methodology for conducting a BART control analysis;
- Provided presumptive control limits for electricity generating units (EGUs) larger than 750 Megawatts (i.e. "presumptive BART");
- Provided a justification for the use of the Clean Air Interstate Rule (CAIR) as BART for CAIR state EGUs.[4]

Beyond the specific elements listed above, EPA provided the states with a great degree of flexibility in how they choose to implement the BART program. The following section summarizes the core requirements for state compliance with BART regulations.

B. Overview of State BART Requirements

As finally promulgated, States are required to undertake three key steps to comply with the BART requirements of the Regional Haze Rule. These steps include:

- Determining if a source is BART-eligible;
- Determining if a source reasonably causes or contributes to visibility impairment in any Class I area (i.e., BART-subject);
- Determining if additional controls or emission limits are necessary (i.e., BART determination).

As stated earlier, eligibility is limited to sources in one of 26 source categories that had units installed and operating between 1962 and 1977 with the current cumulative potential to emit more than 250 tons per year of a visibility impairing pollutant. Once a source is found to be "eligible" for the BART program, states must determine if that source is "subject to BART," that is, if it causes haze or contributes to the formation of haze at any Class I area. EPA's 2005 rule outlines three options for a state to determine if a source is subject to BART. These options include:

- ***Individual source assessment (Exemption Modeling)*** **–** This assessment uses CALPUFF or other EPA-approved modeling methods to determine if an individual facility causes or

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[3] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations Under the Regional Haze Rule.
[4] Massachusetts did not use CAIR as a basis for making BART determinations or for other strategies to reduce emissions. Therefore, the future EPA replacement rule for CAIR, which is mandated by the Courts, does not impact BART determinations for Massachusetts BART-eligible sources.

contributes to haze at any Class I areas or if that source might be exempted. Results of the modeling are compared to natural background conditions. EPA defined "cause" as an impact of 1.0 deciview or more, and "contribute" as an impact of 0.5 deciview or more.[5] The rule, however, gave states discretion to set lower thresholds for contribution. Massachusetts has determined that "contribute" will be defined as an impact of 0.1 deciview or more, as described in Section D.

- ***Cumulative assessment of all BART "eligible sources"*** **–** Under this method, a state can choose to find that all eligible sources within a geographic area or region are subject to BART. This method could also be used to analyze an area's contribution to visibility impairment and demonstrate that *no* sources are subject, based on cumulative modeling. The cumulative modeling of all BART-eligible sources within a state can be used independently for the different visibility-impairing pollutants. For example, if all BART-eligible sources within a state were found to have $PM_{2.5}$ emissions that cumulatively did not impact visibility at any nearby Class I areas, then that state could propose to exempt these sources from being subject to BART for $PM_{2.5}$. These same BART-eligible facilities would still be subject to BART for the other visibility-impairing pollutants such as SO_2 and NOx.
- ***Assessment based on model plants*** **–** This method provides a mechanism to exempt sources with common characteristics that are found not to impair visibility at Class I areas. For example, BART-eligible facilities emitting less than a certain level of VOCs that are located greater than 200 kilometers from all Class I areas and that do not emit any other types of visibility-impairing pollutants could be exempted from BART.

Once a source has been identified as BART-eligible and "subject" to BART, it must conduct an engineering review to determine if the installation of new control requirements is appropriate.[6] This review takes into consideration five factors:

- The costs of compliance
- The energy and non-air quality environmental impacts of compliance
- Any existing pollution control technology in use at the emission unit
- The remaining useful life of the emission unit
- The degree of visibility improvement which may reasonably be anticipated from the use of BART.

C. BART-Eligible Sources in Massachusetts

Based on the MANE-VU Contribution Assessment (Appendix A), every MANE-VU state with BART-eligible sources contributes to visibility impairment at a Class I area to a significant degree. Therefore, MANE-VU continues to support the policy decision made by the MANE-VU

[5] Impacts are based on the difference in deciviews (delta deciview) calculated between the best twenty percent natural visibility conditions (states have the option to use annual average conditions as an alternative) at a Class I site with and without individual source contributions included.

[6] A possible exception to this requirement would exist in the case where a state has adopted an alternative program that would take the place of a source-specific BART determination, as outlined in 40 CFR §51.308(e)(2). MANE-VU has two states that are adopting such programs at this time: Connecticut and Maryland.

Board in June 2004, that ***if a source is eligible for BART, it is subject to BART***. (i.e., no exemption test will be used). The reasons why MANE-VU has chosen to pursue this option for demonstrating its sources are reasonably anticipated to cause or contribute to visibility impairment at Class I areas are threefold: (1) the BART sources represent an opportunity to achieve greater reasonable progress; (2) additional public health and welfare benefits will accrue from resulting decreases in fine particulate matter; and (3) to demonstrate its commitment to federal land managers (FLMs) and other RPOs as it seeks emissions reductions wherever it is reasonable to do so.

Massachusetts identified its BART-eligible sources using the methodology in the Guidelines for Best Available Retrofit Technology (BART) Determinations under the Regional Haze Rule, 40 CFR Part 51, Appendix Y. Seventeen sources were found to be eligible for BART and are listed in
Table 1. These include nine electric generating units (EGUs), four industrial/commercial/institutional (ICI) boilers/chemical processing plants, one municipal waste combustor (MWC), and three petroleum storage facilities.

Table 1: BART-Eligible Facilities in Massachusetts

I.D.	Source	Units	Type
1190012	Boston Generating - New Boston	Unit 1	EGU
1190128	Boston Generating – Mystic	Unit 7	EGU
1190491	Braintree Electric	Unit 3	EGU
1200061	Dominion - Brayton Point	Units 1, 2, 3, and 4	EGU
1190194	Dominion - Salem Harbor	Unit 4	EGU
1190092	Harvard University - Blackstone	Units 11 and 12	EGU
1200054	Mirant - Canal Station	Units 1 and 2	EGU
1190093	Mirant - Kendall LLC	Units 1 and 2	EGU
1200067	TMLP - Cleary Flood	Units 8, 9 and 9A	EGU
1190175	Eastman Gelatin	Units 1, 2, 3 and 4	ICI Boilers/Chemical Processing
1190138	General Electric Aircraft - Lynn	Unit 3	ICI Boilers/Chemical Processing
420086	Solutia	Units 9 and 10	ICI Boilers/Chemical Processing
1190507	Trigen - Kneeland St	Unit 3	ICI Boilers/Chemical Processing
1197654	Wheelabrator – Saugus	Units 1 and 2	Municipal Incinerator
1190484	Exxon Mobil – Everett	All Process Units	Petroleum Storage
1190487	Global Petroleum – Revere	All Process Units	Petroleum Storage
1190483	Gulf Oil – Chelsea	All Process Units	Petroleum Storage

D. *The Degree of Visibility Improvement That May Reasonably Be Anticipated from the Use of BART*

BART emission limits must be determined subject to an evaluation of the five statutory factors. These factors include:

(a) the costs of compliance,
(b) the energy and non-air quality environmental impacts of compliance,
(c) any existing pollution control technology in use at the source,
(d) the remaining useful life of the source, and
(e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

To begin its analysis of these factors, MANE-VU first considered the degree of visibility improvement that could result from the installation of BART controls. This enabled MANE-VU to estimate the maximum visibility benefit that is achievable from the use of BART. It also provides a useful metric for determining which sources contribute most significantly to regional haze and which sources are unlikely to warrant BART controls.

Modeling of BART Visibility Impacts

The MANE-VU modeling of BART visibility impacts used 2002 emissions of SO_2, NO_X, and PM_{10} from all BART-eligible units in the region, including all BART-eligible sources in Massachusetts.[7] The NWS and MM5 meteorological platforms were both used to model each BART-eligible unit's maximum 24-hr, 8th highest 24-hr, and annual average impact at the Class I area most heavily impacted, as well as the total impact from all BART sources on each Class I area. These visibility impacts were modeled relative to 20 percent best days, 20 percent worst days, and annual average natural background conditions. For the purposes of this analysis, MANE-VU examined the 24-hr maximum visibility impact relative to the 20 percent best days. On July 19, 2006, EPA provided clarification to guidance that states may use either estimates of 20 percent best or annual average natural background visibility conditions as the basis for calculating the deciview difference that individual sources would contribute for BART exemption modeling purposes. MANE-VU has opted to use the best conditions estimates for their consideration of the "degree of visibility improvement" modeling because it is more protective to the region.

In July of 2004, MANE-VU submitted comments to EPA that included visibility impact analysis of a representative sample of EGUs across the country. Based on that representative sample, MANE-VU determined that the value of the maximum 24-hour impact relative to natural conditions that would include 98 percent of the cumulative visibility impact on MANE-VU sites was likely between 0.1 and 0.2 deciview (dv). However, this dataset was limited in that it only

[7] Emissions information was gathered from the MANE-VU 2002 Version 2 (Base A) emissions inventory. Since then, the MANE-VU 2002 Version 3 (Base B) emissions inventory has been developed which includes several changes made by the OTC modeling committee.

explored the relationship of EGUs and did not provide an indication of how the total frequency impact might change with numerous smaller, non-EGU, BART-eligible sources.

MANE-VU was able to repeat this analysis for the dataset that included all BART-eligible units in the region. This analysis remains limited in that it includes only MANE-VU sources. It is likely that the additional sources from VISTAS and MWRPO would add to the total visibility impairment experienced at MANE-VU class I areas and, to some extent, to the top 98 percent of the visibility impacts. Without knowing the exact contribution of extra-regional BART sources to impairment at MANE-VU Class I sites, it is impossible to determine the cumulative 98th percentile frequency precisely.

Notwithstanding this limitation, the results of this new analysis showed that 98 percent of the cumulative frequency visibility impact from all MANE-VU BART-eligible sources corresponds to a maximum 24-hr impact of 0.22 dv from the NWS-driven data and 0.29 dv from the MM5 data. MANE-VU therefore concluded that a range of 0.2 to 0.3 dv would represent a “significant” impact at MANE-VU Class I areas on an average basis. Given the analysis and the limitation due to exclusion of sources outside of MANE-VU, MANE-VU decided to place increased weight on sources with an individual visibility impact greater than 0.1 dv. This threshold is overly inclusive relative to exemption processes being conducted by other RPOs, but still provides MANE-VU states flexibility in choosing the weight to be given to the first of the five factors they considered (i.e., the degree of visibility improvement that could result from BART).

Visibility Impacts of Massachusetts BART-Eligible Sources

The specifics of the visibility modeling conducted for BART-eligible sources in Massachusetts as well as the rest of the MANE-VU states can be found in Appendix R. The results of CALPUFF modeling using MM5 and NWS meteorological platforms for Massachusetts BART-eligible facilities are found in Table 2 and

Table 3, respectively. VOC emissions, while significant and potential contributors to visibility impairment, are not well modeled by Lagrangian Dispersion models such as CALPUFF; thus Exxon Mobil – Everett, Global Petroleum – Revere, and Gulf Oil – Chelsea, were not included. These results display facility-wide impacts on the worst day at the site experiencing the largest impact relative to the 20 percent best natural background conditions.

Table 2: CALPUFF Visibility Modeling Results using MM5 Platform

	MM5- Impact on Worst Day Relative to 20 Percent Best Natural Conditions (delta deciview; ddv)				
Facility	*Class I Site*	*Total*	*SO4*	*NO3*	*PM10*
Dominion - Brayton Point	Acadia	11.152	9.740	3.354	0.031
Mirant - Canal Station	Acadia	6.643	6.018	1.310	0.000
Mystic Station	Moosehorn Wilderness	1.023	0.943	0.117	0.002
Dominion - Salem Harbor	Moosehorn Wilderness	0.982	0.886	0.151	0.001
Trigen - Kneeland Station	Acadia	0.146	0.023	0.127	0.001
Wheelabrator-Saugus	Acadia	0.250	0.026	0.232	0.000
General Electric Aircraft - Lynn	Acadia	0.239	0.148	0.092	0.000
TMLP - Cleary Flood[8]	Acadia	0.103	0.028	0.076	0.003
Mirant - Kendall	Acadia	0.095	0.015	0.082	0.000
Harvard University - Blackstone	Acadia	0.060	0.039	0.027	0.001
New Boston	Presidential Range	0.044	0.000	0.044	0.000
Braintree Electric	Acadia	0.031	0.004	0.029	0.000
Eastman Gelatin	Acadia	0.029	0.002	0.026	0.000
Solutia	Presidential Range	0.003	0.000	0.003	0.000

Table 3: CALPUFF Visibility Modeling Results using NWS Platform

	NWS- Impact on Worst Day Relative to 20 Percent Best Natural Conditions (ddv)				
Facility	*Class I Site*	*Total*	*SO4*	*NO3*	*PM10*
Dominion - Brayton Point	Moosehorn Wilderness	7.200	6.206	1.754	0.026
Mirant - Canal Station	Acadia	3.485	3.251	0.427	0.000
Mystic Station	Moosehorn Wilderness	0.660	0.556	0.108	0.003
Dominion - Salem Harbor	Acadia	0.545	0.488	0.108	0.001
Trigen - Kneeland Station	Lye Brook Wilderness	0.097	0.005	0.092	0.002
Wheelabrator - Saugus	Lye Brook Wilderness	0.183	0.004	0.179	0.000
General Electric Aircraft - Lynn	Acadia	0.159	0.118	0.085	0.000
TMLP - Cleary Flood	Moosehorn Wilderness	0.061	0.022	0.037	0.002
Mirant - Kendall	Lye Brook Wilderness	0.059	0.003	0.057	0.000
Harvard University - Blackstone	Acadia	0.034	0.023	0.010	0.001
New Boston	Lye Brook Wilderness	0.028	0.000	0.027	0.001
Eastman Gelatin	Acadia	0.025	0.002	0.024	0.000
Braintree Electric	Moosehorn Wilderness	0.014	0.002	0.012	0.000
Solutia	Acadia	0.003	0.000	0.003	0.000

[8] TMLP is Taunton Municipal Lighting Plant

E. Overview of Massachusetts BART-Eligible Sources

Exempted Source

As stated earlier, BART eligibility is limited to sources in one of 26 source categories that had units installed and operating between 1962 and 1977 with the current cumulative potential to emit more than 250 tons per year of a visibility impairing pollutant. By accepting a permit limit of 250 tpy for each visibility-impairing pollutant (NOx, SO_2, and PM10), a facility can be exempted from BART due to ineligibility. General Electric – Lynn has informed MassDEP that it will be applying for a permit cap of less than 250 tpy for NOx and SO_2 emissions from Unit 3 in order to become exempt from BART requirements; PM10 emissions are already capped at less than 250 tpy. Therefore, no BART determinations are being proposed for General Electric – Lynn Unit 3.

Sources with VOC Emissions

Massachusetts has three BART-eligible sources that have VOC emissions from petroleum storage: Exxon Mobil – Everett, Global Petroleum – Revere, and Gulf Oil – Chelsea. BART for these sources is described below in Section J.

Sources with De Minimis Impacts on Visibility

According to Section III of the 2005 Regional Haze Rule, once a state has compiled its list of BART-eligible sources, it needs to determine whether to make BART determinations for all of the sources or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area.

MANE-VU has identified a set of sources whose potential "degree of visibility improvement" is so small (<0.1 ddv) that no reasonable weighting could justify additional controls under BART. (Note that the cumulative impact of all of these sources is lower than EPA's guidance which states that the threshold for determining whether a source "contributes" to visibility impairment should be ≤0.5 dv.) The documentation for this modeling can be found in Appendix R. MANE-VU has termed these sources to have a "de minimis visibility impact."

For Massachusetts, sources meeting this criterion are listed in Table 4. Trigen – Kneeland has been added to this list, despite its modeled impact of 0.146 ddv using the MM5 modeling platform, due to two significant errors in the 2002 input data used by MANE-VU to screen facilities for their impact on visibility. First, Units 1-4 were included in the modeling when only Unit 3 is BART-eligible. Second, the 2002 modeled NOx emissions from Unit 3 were 396 tons, rather than the actual 96 tons of NOx emissions. Massachusetts believes that modeling using the corrected 2002 NOx emissions from Trigen - Kneeland would indicate a total visibility impact of <0.1 ddv, therefore Trigen – Kneeland is being considered a source with de minimis impact on visibility.

Table 4: Massachusetts Sources with De Minimis Visibility Impact

I.D.	Source	Type
1190491	Braintree Electric	EGU
1190092	Harvard University - Blackstone	EGU
1190093	Mirant - Kendall LLC	EGU
1190012	New Boston	EGU
1190175	Eastman Gelatin	ICI Boilers/Chemical Process
420086	Solutia	ICI Boilers/Chemical Process
1190507	Trigen - Kneeland	ICI Boilers

MassDEP has determined that the visibility improvement that would be achieved by the installation of BART controls at these sources does not justify the installation of such controls. The BART analyses to support these determinations are described in the sections below.

Sources that Contribute to Visibility Impairment

Massachusetts BART-subject sources with a greater than *de minimis* impact on visibility include three coal-fired EGUs (Brayton Point Units 1-3), eight oil-fired EGUs (Brayton Point Unit 4, Canal Station Units 1-2, Mystic Station Unit 7, Salem Harbor Unit 4, and Cleary Flood Units 8, 9 and 9A) and two MWC units (Wheelabrator – Saugus). An overview of the fuel sources, boiler types, and 2002 operating hours and heat input rates is also contained in Table 5.

Table 5: Overview of BART-Eligible EGUs, ICI Boilers & MWCs

Source Type	I.D.	Source	Unit	Subject to Presumptive BART[3]?	Primary Fuel	Secondary Fuel(s)	Unit Type	Built Year
EGU	1200061	Brayton Point	1	yes	Coal (1.5%S)	Natural Gas, Residual Oil	Tangentially-fired	1963
EGU	1200061	Brayton Point	2	yes	Coal (1.5%S)	Natural Gas, Residual Oil	Tangentially-fired	1964
EGU	1200061	Brayton Point	3	yes	Coal (1.5%S)	Natural Gas, Residual Oil	Dry bottom wall-fired boiler	1969
EGU	1200061	Brayton Point	4	yes	Residual Oil	Natural Gas	Dry bottom wall-fired boiler	1974
EGU	1200054	Canal Station	1	yes	Residual Oil	Diesel Oil	Dry bottom wall-fired boiler	1970
EGU	1200054	Canal Station	2	yes	Residual Oil	Diesel Oil, Natural Gas	Dry bottom wall-fired boiler	1976
EGU	1190128	Mystic Station	7	yes	Residual Oil	Natural Gas	Tangentially-fired	1974
EGU	1190194	Salem Harbor	4	yes	Residual Oil		Dry bottom wall-fired boiler	1972
EGU	1200067	Cleary Flood	8	no	Residual Oil	Diesel Oil	Dry bottom wall-fired boiler	1966
EGU	1200067	Cleary Flood	9	no	Natural Gas	Diesel Oil, Residual Oil	Other boiler	1976
EGU	1200067	Cleary Flood	9A	no	Natural Gas	Diesel Oil	Combustion Turbine	1975
MWC	1197654	Wheelabrator - Saugus	1	no	Municipal Solid Waste		Mass burn waterwall boiler	1975
MWC	1197654	Wheelabrator - Saugus	2	no	Municipal Solid Waste		Mass burn waterwall boiler	1975

F. Energy and Non-Air Quality Environmental Impacts, Remaining Useful Life, and Federal Enforceability

The following section provides an overview of the energy and non-air impacts and remaining useful life evaluations for all Massachusetts BART-eligible EGUs, ICI boilers, and MWCs. The existing pollution control technologies, available retrofit control technologies and their estimated costs, and the degree of visibility improvement for each BART-eligible unit are described in later sections focused on SO_2, NOx, and PM emissions at BART facilities.

Energy and Non-Air Quality Environmental Impacts

One potential impact of additional control technology is the requirement for additional energy use and a resulting increase in carbon dioxide emissions. In contrast, fuel switching is a potential control strategy that could decrease carbon emissions if a lower carbon fuel were used (i.e., coal to oil, or coal or oil to natural gas). These effects would be important particularly if carbon emissions are limited in the future under climate change mitigation strategies. Given the uncertainty of potential national carbon regulations, the impact of increased carbon emissions cannot yet be fully assessed. For some Massachusetts BART-eligible facilities, carbon emissions are already limited by 310 CMR 7.70, the Massachusetts CO_2 Budget Trading Program; these sources may incur additional costs for BART controls or may accumulate additional carbon credits for trading, depending upon their BART determinations.

An environmental benefit of BART controls, in addition to improved visibility, is the impact on acid deposition in Massachusetts and Northern New England. Reductions in ambient concentrations of SO_2 and NO_x will reduce acid deposition as well as excess nitrogen deposition, thereby reducing the acidification of lakes, streams and soils and material damage to buildings, and the eutrophication of inland and coastal waters.

Remaining Useful Life

As a member of MANE-VU, Massachusetts has determined that a BART-eligible source that is found to have reasonable control options available to it should either control emissions from that BART-eligible source prior to March 31, 2014, or accept a federally enforceable permit limitation or retirement date prior to adoption of this SIP.

Schedule for BART Implementation

40 CFR 51.308(e)(1)(iv) requires that BART controls must be in operation for each applicable source no later than five years after SIP approval. MassDEP is requiring all BART-eligible sources to comply with all BART determinations, including installation and operation of BART controls, as expeditiously as practicable, but in no case later than March 31, 2014.

40 CFR 51.308(e)(1)(v) requires that each source subject to BART maintain the controls required by BART and establish procedures to ensure such equipment is properly operated and

maintained. Massachusetts will meet this requirement by promulgating a BART regulation and by amending the facility's Emission Control Plan to include the BART controls.

Federal Enforceability of BART Determinations

BART determinations are required to be federally enforceable. Massachusetts will incorporate BART determinations into federally enforceable Title V operating permits through an Emission Control Plan amendment.

G. Massachusetts BART Determinations for SO_2

The following section describes SO_2 control technologies and costs and the existing pollution control technologies, degree of visibility improvement reasonably expected and proposed BART determinations for each BART-eligible unit.

Massachusetts BART-eligible sources contributing to visibility impairment include three coal-fired EGUs (Brayton Point Units 1-3), eight oil-fired EGUs (Brayton Point Unit 4, Canal Station Units 1-2, Mystic Station Unit 2, Salem Harbor Unit 4, and Cleary Flood Units 8, 9 and 9A) and two MWC units (Wheelabrator – Saugus Units 1 and 2). An overview of the fuel sources, 2002 and 2007 SO_2 emissions, sulfur contents for residual fuel oil, and current and planned controls at these facilities is contained in Table 6. Also included are the proposed BART determinations (“Proposed SO_2 BART”), as explained further below. Collectively, these six BART facilities emitted 68,329 tons of SO_2 that diminished visibility in New England Class I areas by 10.523-17.615 ddv in 2002.

Table 6: Massachusetts SO_2 BART Sources, Emissions and Controls

I.D.	Source	Unit	SO_4 ddv	Primary Fuel	Secondary Fuel(s)	Permitted No. 6 Oil Sulfur	2007 No. 6 Oil Sulfur	2002 SO_2 Emissions (tpy)	2007 SO_2 Emissions (tpy)	Current & Planned SO_2 Controls	Proposed SO_2 BART
1200061	Brayton Point	1	9.74, 6.206	Coal (1.5%S)	Natural Gas, Residual Oil	2.2%	none burned in 2007	9,253.52	7,374.393	SDA	0.15#/MMBtu
1200061	Brayton Point	2		Coal (1.5%S)	Natural Gas, Residual Oil	2.2%	none burned in 2007	8,852.74	6,723.277	SDA	0.15#/MMBtu
1200061	Brayton Point	3		Coal (1.5%S)	Natural Gas, Residual Oil	2.2%	none burned in 2007	19,450.29	15,942.651	SO_2 post-combustion control	0.15#/MMBtu
1200061	Brayton Point	4		Residual Oil	Natural Gas	2.2%	1.26%	2,036.91	741.281		0.5% S oil
1200054	Canal Station	1	6.018, 3.251	Residual Oil	Diesel Oil	1.5%	0.50%	13,065.86	5,168.969		0.5% S oil
1200054	Canal Station	2		Residual Oil	Diesel Oil, Natural Gas	1.5%	0.49%	8,948.20	1,506.198		0.5% S oil
1190128	Mystic Station	7	0.943, 0.556	Residual Oil	Natural Gas	1.0%	1.00%	3,727.31	1,922.387		0.5% S oil
1190194	Salem Harbor	4	0.886, 0.488	Residual Oil		2.2%	0.51%	2,886.12	164.350		0.5% S oil
1200067	Cleary Flood	8	0.028, 0.022	Residual Oil	Diesel Oil	2.2%	0.96%	39.23	14.435		0.5% S oil
1200067	Cleary Flood	9		Natural Gas	Diesel Oil, Residual Oil	2.2%	0.95%	67.61	32.575		0.5% S oil
1200067	Cleary Flood	9A		Natural Gas	Diesel Oil	N/A	N/A	1.00	2.600		0.5% S oil
1197654	Wheelabrator - Saugus	1	0.026, 0.004	Municipal Waste				42.00	26.90	SDA	29 ppm or 75% control, whichever is less*
1197654	Wheelabrator - Saugus	2						42.00	27.00		

*The proposed SO_2 BART determination for Wheelabrator – Saugus is the currently permitted level of SO_2 control.

Control Technologies and Costs for SO2 Emissions

A variety of control technologies are available to control SO_2 emissions from EGUs and ICI boilers, as described below.

Table 7 indicates the cost ranges for these control technologies. Further descriptions of these controls and their costs can be found in Appendices Q, T and U.

Table 7: SO_2 Control Technology Costs

Source Category	*Control*	*Cost*	*Units*	*Cost Range*
EGUs	Wet/Dry Scrubbers (FGD)	200-500	Dollars per ton SO2	Low
ICI Boilers	Wet/Dry Scrubbers	800-8,000	Dollars per ton SO2	Mid to High

Wet Flue Gas Desulphurization

Flue gas desulphurization (FGD) processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. Wet regenerable FGD processes (meaning the reagent material can be treated and reused) are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal wastewater discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems.

Spray Dry Flue Gas Desulphurization

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubber) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate sludge as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas, along with fly ash, and are collected in a PM collection device. This process produces dry reaction waste products for easy disposal. The SO_2 removal efficiencies of existing lime spray dryer systems range from 60-95%.

Dry Flue Gas Desulphurization

For the dry injection process, dry powdered lime (or another suitable sorbent) is injected directly into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO_2 removal efficiencies of existing dry injection systems range from 40-60%.

Low-Sulfur Fuels

EGUs and ICI boilers generally burn either distillate fuel (#2 oil) or residual fuel oil (#6 oil). The maximum allowable sulfur content of #2 fuel oil is currently 0.5 percent. It is readily available in the Northeast, as is an 0.05 percent #2 oil and an ultra-low sulfur #2 oil (0.0015 percent, i.e. 15 ppm). US EIA data for the year 2006 for the Northeast indicate that 0.5 percent, 0.05 percent, and 0.0015 percent sulfur #2 oils had supply fractions of 44 percent, 13 percent, and 42 percent, respectively.

Residual fuel oil (#6 oil) is more commonly used in EGUs and ICI boilers as a primary or secondary fuel because of its lower cost (per MMBtu). It is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of #6 oil in ICI boilers. The allowable sulfur content for #6 oil in Massachusetts varies from 0.5 to 2.2 percent, depending on the region. A wide range of sulfur contents in oil is available, from less than 0.3 percent to 3 percent. 2006 US EIA data provides information about available stocks for the #6 oil in three sulfur fractions: less than 0.3 percent (35 percent), 0.3 to 1 percent (39 percent), and greater than 1 percent sulfur (26 percent), indicating ample supplies of all three in the Northeast.

SO_2 emissions are directly related to the sulfur content of the fuel burned. Reducing the amount of sulfur in the fuel (coal or oil) will proportionately reduce SO_2 emissions. This can be accomplished by fuel-switching to a lower sulfur content coal or oil or by switching to natural gas; for coal, another option to reduce sulfur content is coal cleaning.

Low-Sulfur Fuel as BART for SO_2 Emissions from Oil-Fired, BART-Eligible Units

Massachusetts has seven primarily oil-fired EGUs (Brayton Point Unit 4, Canal Station Units 1-2, Mystic Station Unit 2, Salem Harbor Unit 4, and Cleary Flood Units 8 and 9) that are BART-eligible and contribute to visibility impairment. Each of these facilities currently combust residual oil as a primary fuel. An analysis of the first four BART factors for the MANE-VU low-sulfur fuel strategy, which proposes reducing the sulfur content in distillate and residual oils, is applicable to these BART analyses and can be found in the Long-Term Strategy, Chapter 10.

MassDEP asked for an evaluation of the cost and estimated reductions that would result from burning lower-sulfur fuels, including residual and distillate, in response to FLM comments (Appendix D). The sources which performed this analysis included Brayton Point, Salem

Harbor, Canal Station, Mystic Station and TMLP – Cleary Flood. The fuels and sulfur contents evaluated were #6 residual oil at 0.5% and 0.3% sulfur contents, and #2 distillate oil at 0.3%, 0.05% (500 ppm), and 0.0015% (15 ppm) sulfur contents. TMLP – Cleary Flood was only asked to evaluate lower sulfur #6 residual oil because of timing: results from other facilities' preceding lower sulfur fuel analyses made it apparent that distillate oil was significantly less cost-effective than lower sulfur residual oil (see following discussion on coordinated BART determinations). Results of these evaluations are presented below in Table 8.

In all cases, the cost-effectiveness was based on a comparison with 1.0% S residual oil. Costs reflect only the differential cost of fuel and do not include any capital investments that might be required. For Salem Harbor Unit 4 and Brayton Point Unit 4, the cost in $/dv is also presented (in millions dollars). Mystic and Canal Stations and TMLP – Clearly Flood did not perform visibility modeling, therefore no costs in $/deciview are provided. Based upon similar costs in $/ton and relative geographic proximity, it is likely that the cost in $/dv for these units would be in a similar range as those for Salem Harbor 4 and Brayton Point 4 for the residual oil options.

Most of these facilities combusted residual oil with a lower sulfur content than their permitted limits in the years 2004-2007, as can be seen in Table 8. An analysis of the five large EGUs in this group (including Brayton Point Unit 4, Canal Station Units 1 & 2, Mystic Station Unit 7, and Salem Harbor Unit 4) indicates that they represent a significant portion of the Massachusetts residual oil market. In 2007, 3 of the 5 units burned approximately 0.5% sulfur residual oil, 1 burned 1.0%, and only 1 burned > 1.0%. These five units reported the combustion of 199,365,421 gallons of residual oil; this amounts to 67.9% of all the residual oil sold in Massachusetts in 2007. Thus, the BART-eligible EGUs combust a significant majority of the residual oil sold in the Commonwealth.

Table 8: Lower Sulfur Oil BART Analyses Summary

Fuel Sulfur Content		#2 Distillate Oil				#6 Residual Oil				
		500 ppm		15 ppm		0.5%		0.3%		
Facility	**%S #6 Oil Burned '04-'07**	**$/ton**	**$/dv**	**$/ton**	**$/dv**	**$/ton**	**$/dv**	**$/ton**	**$/dv**	**Oil Price Dates**
Mystic Station 7	1.00%	$16,453		$15,893		$4,270		$4,259		4/1/08-3/19/09
Canal Station 1 & 2	0.50%	$14,775		$14,535		$3,170		$3,838		4/1/07-3/31/09
Salem Harbor 4	0.51%	$4,696	$33.6 M	$5,880	$43.1 M	$3,041	$25.1 M	$4,213	$31.8 M	3/30/09
Brayton Point 4	1.26-1.43%	$4,696	$44.1 M	$5,880	$56.8 M	$3,041	$33.9 M	$4,658	$42.7 M	3/30/09
TMLP – Cleary Flood 8 & 9	1.00%					$2,300 -2,500		$3,782-6,942		1/1/09-6/30/09

The discrepancy in the oil costs per ton, for both residual and distillate oils, between the different facilities may be attributable to the use of different oil price dates by each of the facilities. Dominion (which owns both Salem Harbor and Brayton Point) used a price from a single date, while TMLP – Cleary Flood used a six-month average, Mystic Station used a year-long average and Canal Station used a two-year average. Because extreme price volatilities for oil occurred during these time periods, it is reasonable to conclude that a great deal of the variability in the cost per ton is due to the use of differing time periods.

MassDEP believes it is important to make BART determinations for these EGUs in a coordinated fashion, based on an analysis of data from all the facilities, in part because the cost/ton is primarily determined by the cost of the fuel (i.e., the cost/ton data would likely have been more comparable if the same oil price dates were used). Additionally, these facilities are in direct economic competition with one another.

MassDEP has determined that a switch to distillate oil is not cost-effective for these BART facilities given the high costs per ton and probable additional capital costs. Additional capital costs to install new burners, fuel pumps, controls, and fuel tanks would be incurred by some of the facilities to combust distillate oil, but these costs were not included in the cost-effectiveness data.

For lower sulfur residual oil, the results of the BART analyses for lower sulfur fuels were fairly consistent between the oil-fired BART facilities. MassDEP has therefore determined that switching to 0.5% sulfur #6 residual oil is a cost-effective means to reduce the SO_2 emissions that contribute to regional haze for Mystic Station Unit 7, Canal Station Units 1 and 2, Salem Harbor Unit 4, Brayton Point Unit 4 and TMLP – Cleary Flood Units 8 and 9. Further reductions of SO_2 emissions may result from the limited capacities proposed as NOx BART for these units, as described below. The BART determination for these facilities is to restrict the sulfur content of delivered residual fuel oil to 0.5% beginning March 31, 2014.

MassDEP did not request oil-burning BART facilities to evaluate the costs or visibility impacts of flue gas desulphurization (FGD), as was suggested by the FLMs. FGD is not yet a commonly employed strategy to control SO_2 emissions from oil-fired boilers in the United States. Additionally, the EPA BART Guidelines for oil-fired boilers suggest evaluation of limiting the sulfur content of the fuel. Finally, MANE-VU has not selected FGD on oil-fired units as a priority strategy. Therefore, MassDEP does not believe it is essential to implement FGD on oil-fired boilers at this time. BART-subject facilities with oil-fired units were thus not asked to evaluate FGD in their analyses of SO_2 control options. Massachusetts will continue to evaluate the feasibility and advantages of FGD on oil-fired units in a regional context.

Brayton Point Units 1-3: Presumptive BART for Coal-Fired EGUs

Massachusetts contains three coal-fired EGUs, Brayton Point Units 1-3, which are subject to federal presumptive BART guidelines.[9] The presumptive limit for SO_2 emissions from coal-fired units is 95% removal or 0. 15 lb/MMBtu averaged over a rolling 30-day period.

[9] 40 CFR Part 51 Appendix Y

To control SO_2 emissions, Brayton Point Units 1 and 2 have both recently completed installation of SDAs. Brayton Point Unit 3 will install a dry scrubber or other post-combustion SO_2 controls by March 31, 2014 to meet BART requirements. BART for Brayton Point SO_2 emissions from coal combustion thus consists of the installation and operation of SO_2 post-combustion controls on Unit 3 by March 31, 2014 and compliance by Units 1, 2 and 3 with the presumptive BART limit of 0.15 lb/MMBtu as a 30-day rolling average.

Wheelabrator - Saugus

Massachusetts has one BART-eligible incinerator, Wheelabrator – Saugus, which contains two mass burn incinerators with water wall boilers, each rated at 325 MMBtu/hr heat input. Each boiler produces 195,000 lbs/hr of steam at 650 psi and 850º F. Both incinerator units are BART-eligible with reported 2002 emissions of 84 tons for SO_2.

The existing control technology for SO_2 emissions includes a spray dry absorber (SDA) with lime slurry injection. The required emission limits under 310 CMR 7.08(2)(f)2: Incinerators are 29 ppm or less of SO_2 emissions (by volume at 7 percent oxygen dry basis) or 75 percent reduction by weight from uncontrolled SO_2 levels, whichever is less stringent. Compliance is based on 24-hour geometric mean.

CALPUFF modeling suggests that visibility impacts from SO_2 emissions from Wheelabrator - Saugus are below 0.1 ddv on the worst day at any Class I area. MassDEP has determined that further controls for SO_2 are not recommended due to the fact that the degree of visibility improvement (<0.1 ddv) that could be achieved is not warranted given the additional cost required to install supplementary SO_2 controls.

Facilities with De Minimis Impacts on Visibility

Massachusetts BART-eligible sources with de minimis impacts on visibility include Braintree Electric, Harvard University – Blackstone, Mirant – Kendall, New Boston, Eastman Gelatin, Solutia and Trigen - Kneeland. Collectively, these seven BART facilities emitted 292 tons of SO_2 that diminished visibility in New England Class I areas by 0.035-0.083 ddv in 2002.

MassDEP has determined that the visibility improvement that would be achieved by the installation of BART controls at these sources does not justify the cost of installation of such controls. This is consistent with data from MANE-VU, documented in Appendix R in which the entire MANE-VU population of the sources with a de minimis visibility impact (i.e., <0.1 dv) was modeled together to examine their cumulative impacts on each Class I site. The result showed that the maximum 24-hour impact at any Class I area of all modeled sources with individual impacts below 0.1 dv was only a 0.35 dv change relative to the estimated best days' natural conditions at Acadia National Park. This value is below the 0.5 dv impact recommended by EPA for exemption modeling in which a source not only does not need to install BART controls, but does not need to perform a BART five-factor analysis. However, because MANE-VU has decided that once a source is eligible for BART, it is subject to BART, MassDEP has provided a five-factor analysis for these sources (see Section F and Table 4). The minimal impact of these sources on visibility leads to the conclusion that no reasonable weighting could justify additional controls under BART. Thus, BART for Massachusetts sources with de minimis impacts on visibility consists of their existing SO_2 emission limits.

H. BART for NOx Emissions from EGUs & ICI Boilers

The following section describes NOx control technologies and costs, and the existing pollution control technologies, degree of visibility improvement reasonably expected and proposed BART determinations for each BART-eligible unit.

Massachusetts BART-eligible sources contributing to visibility impairment include three coal-fired EGUs (Brayton Point Units 1-3), eight oil-fired EGUs (Brayton Point Unit 4, Canal Station Units 1-2, Mystic Station Unit 2, Salem Harbor Unit 4, and Cleary Flood Units 8, 9 and 9A), and two MWC units (Wheelabrator – Saugus Units 1 and 2). An overview of the 2002 and 2007 NOx emissions, 2002 and permitted NOx rates, and current and planned controls for these facilities is contained in Table 9. Also included are the proposed BART determinations (“Proposed NOx BART”), as explained further below. Collectively, these six BART-subject facilities emitted 20,824 tons of NOx that diminished visibility in New England Class I areas by 2.613-5.06 ddv in 2002.

Table 9: Massachusetts NOx BART Sources, Emissions, and Controls[10]

I.D.	Source	Unit	NO3 ddv	2002 NOx Emissions (tpy)	2007 NOx Emissions (tpy)	2002 NOx Rate[11] (lb/MMBtu)	2007 NOx Rate[11] (lb/MMBtu)	Permitted NOx Rate (lb/MMBtu)	NOx Controls	Proposed NOx BART	Subject to Presumptive BART?
1200061	Brayton Point	1	3.354, 1.754	2,513.17	858.442	0.294	0.099	0.38	SCR & LNB w/ Closed-coupled/Separated OFA	0.10 #/MMBtu	yes
1200061	Brayton Point	2		2,270.29	1,935.230	0.284	0.23	0.38	LNB w/ Closed-coupled/Separated OFA	0.25 #/MMBtu	yes
1200061	Brayton Point	3		7,337.88	1,965.740	0.399	0.105	0.45	SCR & LNB w/ OFA	0.10 #/MMBtu	yes
1200061	Brayton Point	4		552.05	183.715	0.199	0.188	0.27	LNB	283.824 tpy[12]	yes
1200054	Canal Station	1	1.13, 0.427	3,338.85	402.333	0.228	0.037	0.28	SCR & LNB w/ OFA	0.080 #/mmbtu	yes
1200054	Canal Station	2		2,259.98	654.305	0.229	0.197	0.28	SNCR & LNB w/ OFA	0.160 #/mmbtu	yes
1190128	Mystic Station	7	0.117, 0.108	804.51	684.382	0.098	0.078	0.25	Combustion Modification	3,580.617 tpy[12]	yes
1190194	Salem Harbor	4	0.151, 0.108	787.36	69.523	0.258	0.212	0.28	LNB	294.336 tpy[12]	yes
1200067	Cleary Flood	8	0.076, 0.037	12.46	4.600	0.257	0.254	0.28	LNB	0.28 #/mmbtu	no
1200067	Cleary Flood	9		160.78	24.343	0.141	0.153	0.28	Water Injection LNB w/ OFA	0.28 #/mmbtu	no
1200067	Cleary Flood	9A		66.00	12.510			0.28	Water Injection	0.28 #/mmbtu	no
1197654	Wheelabrator - Saugus	1	0.232, 0.179	357.00	277.500			205 ppm	SNCR & LNB	TBD	no
1197654	Wheelabrator - Saugus	2		364.00	322.000					TBD	no

[10] Abbreviations used in this table: SDA, spray dry absorber; SCR, selective catalytic reduction; LNB, low-NOx burner technology; OFA, overfire air; DS, dry scrubber; SNCR, selective non-catalytic reduction.
[11] NOx Emission Rates have been obtained for units reporting to EPA's Clean Air Market Division (CAMD). Clearly Flood Unit 9A and Wheelabrator – Saugus do not report to CAMD, therefore no NOx emission rates are available for these units.
[12] Proposed NOx BART determinations for low-capacity units are provided in tons per year (tpy) and are further described below.

Control Technologies and Costs for NOx Emissions

A variety of control technologies are available to control NOx emissions from EGUs and ICI boilers, as described below. Table 10 indicates the cost ranges for these control technologies. Further descriptions of these controls and their costs can be found in Appendices Q, T and U.
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Table 10: NOx Control Technology Costs

Source Category	***Control***	***Cost ($/ton)***	***Units***	***Cost Range***
EGUs	Flue Gas Recirculation	500-2,000	Dollars per ton NOx	Mid
EGUs	Low-NOx Burners	200-500	Dollars per ton NOx	Low
EGUs	Overfire Air	250-600	Dollars per ton NOx	Low
EGUs	SCR	1,000-1,500	Dollars per ton NOx	Mid
EGUs	SNCR	500-700	Dollars per ton NOx	Mid
ICI Boilers	Low NOx-Burners	200-3,000	Dollars per ton NOx	Mid
ICI Boilers	SNCR	1,300-10,000	Dollars per ton NOx	Mid to High
ICI Boilers	SCR	4,000-15,000	Dollars per MMBtu/hr	High

Firing Configuration and Firing Practices

Firing configuration and firing practices can result in a 5-60% reduction in NO_x formation. Firing configuration is a design characteristic of the boiler. Firing practices include such things as flue-gas recirculation, low NO_x burners, low excess air, staged combustion, reduced air preheat, and fuel substitution/alteration.

Operating at low excess air involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. This method may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of this technique may also reduce operational flexibility; however, it may reduce NO_x by 10-20% from uncontrolled levels.

Flue-gas recirculation involves reinserting a portion of the flue-gas into the combustion chamber. The reduced oxygen content of the reused air will inhibit the production of NO_x.

Staged combustion involves a fuel-rich combustion zone, followed by a secondary combustion zone in which excess air is introduced.

Reduced air preheat involves bypassing the combustion air preheater and thus lowering the combustion temperature and reducing the formation of thermal NO_x.

Low NO_x burners are designed to control fuel/air mixing and increase heat dissipation. These alternative burners can be installed on new boilers or retrofitted on older units. Low NO_x burners have been shown to reduce NO_x formation by 35-55%.

Fuel substitution requires burning fuel with a lower nitrogen content to inhibit the production of fuel NO_x. The lower the content of nitrogen in a fuel, the lower the resultant NO_x emissions will be.

Overfire Air

Overfire air involves injecting a portion of the total combustion air above the burners. Overfire air limits NOx by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) reducing flame temperature that limits thermal NO_x formation, and/or (3) reducing residence time at peak temperature which also limits thermal NO_x formation. Overfire air can reduce NO_x emissions by 20-30%.

Water/Steam Injection

Water or steam can be injected into the boiler combustion zone to reduce the peak flame temperature. The lower temperature results in a lower rate of formation of thermal NO_x.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25-40% have been achieved.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. The SCR reactor can be located at various positions in the process, including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia to NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. NO_x emission reductions of 75-85% have been achieved through the use of SCR on oil-fired boilers operating in the U.S.

Units with Existing NOx Controls: Brayton Point Unit 1 & 3 and Canal Station Units 1-2

Brayton Point Units 1 and 3 are coal-fired units subject to presumptive BART. They have existing LNB, OFA and SCR, which are the most stringent technologically feasible system of controls available. Brayton Point has proposed that the NOx emission limit for Brayton Point Units 1 and 3 should be a rolling, 30-day average of 0.10 lb/MMBtu, the lowest presumptive NOx BART limit for any boiler type. MassDEP agrees and proposes that BART for Brayton Point Units 1 and 3 is a NOx emission limit of 0.10 lb/MMBtu.

Canal Station Units 1 and 2 are dry bottom wall-fired boilers that burn residual oil. NOx is controlled at Unit 1 with LNB, OFA and SCR and at Unit 2 with LNB, OFA, and SNCR. MassDEP requested that Canal Station provide suggested NOx emission limits for Canal Units 1 and 2 which reflect the control efficiency that is attainable through the use of the existing controls. Canal Station suggested compliance with the Massachusetts regulation 310 CMR 7.29 as BART. MassDEP, however, agrees with the FLM comment that compliance with 310 CMR 7.29, which is a facility-wide emission limit, is inconsistent with the intent of the BART regulations, which are unit-specific. MassDEP therefore is proposing rolling, 30-day average NOx emission limits of 0.080 lb/MMBtu for Unit 1 and 0.160 lb/MMBtu for Unit 2. The proposed NOx emission limit for Unit 1 is based upon the average of actual NOx emission rates for the years 2005-2007. The proposed NOx emission limit for Unit 2 is based upon its SNCR efficiencies of 17% NOx reduction at maximum load and 25% NOx removal at minimum load. MassDEP applied an average NOx reduction efficiency of 21% to the average of actual NOx emission rates for the years 2005-2007 to reach the proposed emission limit of 0.160 lb/MMBtu. The following table presents the NOx emission rates for Canal Station Units 1 and 2 for the years 2002-2007.

Table 11: Canal Station NOx Emission Rates 2002-2007

Facility	Unit	Year	NOx Rate (lb/MMBtu)
Canal Station	1	2002	0.228
Canal Station	1	2003	0.189
Canal Station	1	2004	0.134
Canal Station	1	2005	0.079
Canal Station	1	2006	0.108
Canal Station	1	2007	0.037
Canal Station	2	2002	0.229
Canal Station	2	2003	0.229
Canal Station	2	2004	0.226
Canal Station	2	2005	0.214
Canal Station	2	2006	0.199
Canal Station	2	2007	0.197

Brayton Point Unit 2

Brayton Point Unit 2 is a coal-fired unit that has existing LNB with Overfire Air (OFA); a BART analysis for SNCR and SCR on this unit was requested. The following table presents a summary of its capacity factor and the estimated efficiency and costs of SNCR and SCR.

Table 12: Brayton Point Unit 2 NOx BART Analysis

Facility	SNCR			SCR		
	Efficiency	$/ton	$/dv	Efficiency	$/ton	$/dv
Brayton Point 2	15% (0.22 lb/mmbtu)	$5,929	$33,555,828	80% (0.1 lb/mmbtu)	$20,670	$157,558,027

The estimated costs for SNCR and SCR at Brayton Point Unit 2 are significantly higher than average because of the physical space constraints of this unit. These constraints would require substantial re-engineering in order to accommodate post-combustion NOx controls. MassDEP has thus determined that installation of SNCR or SCR is not cost-effective at Brayton Point Unit 2 in order to reduce NOx emissions and improve visibility. Federal presumptive BART limits for a tangentially-fired boiler burning bituminous coal such as Brayton Point Unit 2 is 0.28 lb/MMBtu NOx. MANE-VU recommended a range of 0.1 – 0.25 lb/MMBtu for presumptive BART. MassDEP believes the MANE-VU recommended range is reasonable and achievable, therefore MassDEP proposes that BART for Brayton Point Unit 2 NOx emissions is a rolling, 30-day average NOx emission limit of 0.25 lb/MMBtu. This emission limit is reasonable and achievable, as evidenced by Brayton Point Unit 2's 2008 NOx emission rate of 0.23 lb/MMBtu.

Low Capacity Units: Brayton Point Unit 4, Mystic Station Unit 7, and Salem Harbor Unit 4

Brayton Point Unit 4, Mystic Station Unit 7, and Salem Harbor Unit 4 are oil-fired units that have existing Low NOx Burners (LNB) and/or Combustion Modification. These units were asked to perform a BART analysis for SNCR and SCR. Each of these units has reduced its operating time and/or capacity factors relative to 2002 (see Table 9). This reduced capacity was reflected in their BART and cost-effectiveness analyses. The following table presents a summary of the estimated efficiency and cost of SNCR and SCR for each of these units.

Table 13: Summary of BART Analyses for Low-Capacity Units

Facility	Base Year/Factor	SNCR			SCR		
		Efficiency	$/ton	$/dv	Efficiency	$/ton	$/dv
Mystic Station 7	average 2007-08 (59.4%)	20%	$12,878		85%	$16,601	
Salem Harbor 4	5%	15%	$64,696	$30,472,716	70%	$17,315	$46,265,658
Brayton Point 4	5%	15%	$64,696	$46,881,102	70%	$17,315	$41,587,108

Mystic Station presented two options for a base year for its BART analysis for Unit 7: 2008 (272 tpy NOx) or an average of 2007-2008 (2007-08 average 478 tpy NOx). Mystic estimated a SNCR efficiency of 20% based on the average operating conditions in 2007-08. MassDEP based its BART determination on the average operating conditions in 2007-08. Mystic Station did not perform visibility modeling, therefore no costs in $/deciview are provided. Based upon similar 2002 NOx emission amounts (in tpy), similar costs in $/ton, and relative geographic proximity, it is likely that Mystic Station 7 would have similar or slightly lower cost/deciview than Salem Harbor 4 for SCR. For SNCR, it is likely that the cost/deciview for Mystic Station 7 would be significantly lower than for Salem Harbor 4. However, the cost-effectiveness of SNCR at nearly $13,000/ton was determined to be too high to require the installation of SNCR. Because of these factors, MassDEP did not require Mystic Station to perform visibility modeling for NOx emissions from Unit 7.

Mystic Station has presented the argument in its BART analysis that due to recent transmission upgrades and fuel cost fluctuations, Unit 7 will continue to be operated at a low capacity in the future. For example, in 2007 Unit 7 emitted 85% of the NOx emitted in 2002 (in tpy) while in 2008, Unit 7 emitted only 34% of the NOx emitted in 2002; the average of 2007-2008 NOx emissions was 59.4% that of 2002. MassDEP has determined that for Mystic's BART analyses to be valid, Unit 7 must accept a permit limit to restrict its operations to a level comparable to the reduced capacity used in the BART analysis. In order to provide as much operating flexibility to the facility as possible, the emission limit was calculated as a tpy NOx emission limit based upon the unit's design capacity, its permitted NOx emission rate limit, and its capacity factor from the BART analysis. Because this unit can burn multiple fuels (oil and natural gas), MassDEP proposes to use the greater NOx emission rate (for oil) to set the annual emission limit in order to preserve fuel flexibility. MassDEP therefore is proposing that BART for NOx emissions from Mystic Station Unit 7 is an emission limit of 3,580.617 tpy, as shown in the following calculation.

Mystic Station Unit 7:

- Oil NOx emission limit: 0.25 lb/MMBtu (24-hour average)
- Natural gas NOx emission limit: 0.20 lb/MMBtu (24-hour average)
- Design Capacity: 5,505 MMBtu/hr
- BART Analysis Capacity Factor (2007-08 average): 59.4%
- Annual NOx Limit: (5,505 MMBtu/hr)(0.25 lb/MMBtu)(8,760 hr/yr)(0.594) / 2000 lb/ton = 3,580.617 tpy

Both Salem Harbor Unit 4 and Brayton Point Unit 4 presented similar arguments regarding low use/capacity as part of their BART analyses. They provided a 5% capacity factor upon which the cost estimates for SNCR and SCR were based. MassDEP has determined that for these analyses to be valid, both units must accept a permit limit to restrict its operations to a level comparable to the reduced capacity used in the BART analysis. In order to provide as much operating flexibility to the facility as possible, the emission limit was calculated as a tpy NOx emission limit based upon the unit's design capacity, its permitted NOx emission rate limit, and its capacity factor from the BART analysis. Because Brayton Point Unit 4 can burn multiple fuels (oil and natural gas), MassDEP proposes to use the greater NOx emission rate (for oil) to set the annual emission limit in order to preserve fuel flexibility. MassDEP therefore is proposing that BART for NOx emissions is an emission limit of 283.824 tpy from Brayton Point Unit 4 and 294.336 tpy from Salem Harbor Unit 4, as shown in the following calculations.

Brayton Point Unit 4:
- Oil NOx emission limit: 0.27 lb/MMBtu (24-hour average)
- Natural gas NOx emission limit: 0.20 lb/MMBtu (24-hour average)
- Design Capacity: 4,800 MMBtu/hr
- BART Analysis Capacity Factor: 5%
- Annual NOx Limit: (4,800 MMBtu/hr)(0.27 lb/MMBtu)(8,760 hr/yr)(0.05) / 2000 lb/ton = 283.824 tpy

Salem Harbor Unit 4:
- Oil NOx emission limit: 0.28 lb/MMBtu (24-hour average)
- Design Capacity: 4,800 MMBtu/hr
- BART Analysis Capacity Factor: 5%
- Annual NOx Limit: (4,800 MMBtu/hr)(0.28 lb/MMBtu)(8,760 hr/yr)(0.05) / 2000 lb/ton = 294.336 tpy

TMLP - Cleary Flood

TMLP – Cleary Flood Units 8, 9 and 9A each operate with low NOx burners. In total, these units emitted 239.24 tons of NOx in 2002 and 41.453 tons of NOx in 2007. The total visibility impact from 2002 emissions was modeled as 0.037-0.076 ddv. MassDEP has determined that additional more stringent controls are not recommended due to the fact that the degree of visibility improvement (<0.1 ddv) that could be achieved is not warranted given the additional cost required to install supplementary NOx controls. This conclusion is supported by comparison with the estimates for SNCR and SCR provided above for Salem Harbor Unit 4 and Brayton Point Unit 4. Brayton Point Unit 4, Salem Harbor Unit 4 and each of the TMLP – Cleary Flood units have LNB. In 2002, TMLP – Cleary Flood emitted 30-43% of the level of emissions as the others; in 2007, it was 22-59%. Thus, installation of SNCR or SCR at TMLP – Cleary Flood would provide less reduction in NOx emissions for a comparable or greater cost. BART for Cleary Flood Units 8, 9 and 9A, therefore, is a permitted NOx emission limit of 0.28 lb/mmbtu as a 30-day, rolling average and year-round operation of existing NOx controls.

Facilities with De Minimis Impacts on Visibility

Massachusetts BART-eligible sources with de minimis impacts on visibility include Braintree Electric, Harvard University – Blackstone, Mirant – Kendall, New Boston, Eastman Gelatin, Solutia and Trigen - Kneeland. Collectively, these seven BART facilities emitted 786 tons of NOx that diminished visibility in New England Class I areas by 0.225-0.338 ddv in 2002.

MassDEP has determined that the visibility improvement that would be achieved by the installation of BART controls at these sources does not justify the cost of installation of such controls. This is consistent with data from MANE-VU, documented in Appendix R in which the entire MANE-VU population of the sources with a de minimis visibility impact (i.e., <0.1 dv) was modeled together to examine their cumulative impacts on each Class I site. The result showed that the maximum 24-hour impact at any Class I area of all modeled sources with individual impacts below 0.1 dv was only a 0.35 dv change relative to the estimated best days' natural conditions at Acadia National Park. This value is below the 0.5 dv impact recommended by EPA for exemption modeling in which a source not only does not need to install BART controls, but does not need to perform a BART five-factor analysis. However, because MANE-VU has decided that once a source is eligible for BART, it is subject to BART, MassDEP has provided a five-factor analysis for these sources (see Section F and Table 4). The minimal impact of these sources on visibility leads to the conclusion that no reasonable weighting could justify additional controls under BART. Thus, BART for Massachusetts sources with de minimis impacts on visibility consists of their existing NOx emission limits.

Wheelabrator - Saugus

Massachusetts has one BART-eligible incinerator, Wheelabrator – Saugus, which contains two mass burn incinerators with water wall boilers, each rated at 325 MMBtu/hr heat input. Each boiler produces 195,000 lbs/hr of steam at 650 psi and 850º F. Both incinerator units are BART-eligible with reported 2002 emissions of 721 tons for NOx.

The current NOx control equipment is identical for both units and includes Low-NOx Burners and SNCR. The 310 CMR 7.08(2)(f)3 emission limits, which apply to municipal waste combustors (MWCs), are 205 ppm or less by volume at 7 percent oxygen dry basis (24-hr daily arithmetic average). These limits reflect a 32 percent reduction in NOx emissions from a baseline uncontrolled emissions at 300 ppm. These limits were established to be consistent with the December 1999 federal MACT determination for existing MWCs.

The current NOx emission limit of 205 ppm for Wheelabrator – Saugus was established by 310 CMR 7.08(2), effective in 2000. This limit meets the emissions limits set in EPA's MACT standard for MWCs with a combustor capacity greater than 250 tons per day. However, the NOx limits established under the federal MACT determination in 1999 are more lenient than the capabilities of current NOx control technologies. Therefore, MassDEP expects to propose revisions to its MWC regulations to further limit NOx emissions to comply with the U.S. EPA's Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Stationary Sources: Large Municipal Waste Combustors, 40 CFR 60 subpart Cb. Analyses to determine the BART NOx emission limit BART for Wheelabrator – Saugus Units 1 and 2 are ongoing and the resulting BART determinations will be shared with EPA and FLMs when made.

I. BART for PM_{10} Emissions from BART-Eligible EGUs & ICI Boilers

Massachusetts BART-eligible sources contributing to visibility impairment include three coal-fired EGUs (Brayton Point Units 1-3), eight oil-fired EGUs (Brayton Point Unit 4, Canal Station Units 1-2, Mystic Station Unit 2, Salem Harbor Unit 4, and Cleary Flood Units 8, 9 and 9A) and two MWC units (Wheelabrator – Saugus Units 1 and 2). An overview of 2002 and 2007 PM_{10} emissions and current and planned controls at these facilities is contained in Table 14. Collectively, these six BART-eligible facilities emitted 1,531 tons of PM_{10} that diminished visibility in New England Class I areas by 0.032-0.037 ddv in 2002.

CALPUFF modeling of PM emissions at these facilities suggests an impact of below 0.1 ddv on the worst day, both for each unit and cumulatively. MassDEP has determined that no additional controls are warranted for primary PM_{10} because the additional cost to install newer, slightly more efficient technology is not justified by the potential visibility benefit.

Table 14: Massachusetts PM_{10} BART Sources, Emissions and Controls

I.D.	Source	Unit	PM_{10} ddv	2002 PM Emissions (tpy)	2002 PM Emissions (tpy)*	2007 PM_{10} Emissions (tpy)	Current & Planned PM Controls
1200061	Brayton Point	1	0.031, 0.026	392	183	196.200	Research-Cottrell ESP + Fabric Filter Baghouse
1200061	Brayton Point	2			85	91.900	Research-Cottrell ESP + Fabric Filter Baghouse
1200061	Brayton Point	3			118	147.400	Research-Cottrell ESP
1200061	Brayton Point	4			6	2.400	ESP
1200054	Canal Station	1	0.000, 0.000	672		189.802	ESP
1200054	Canal Station	2				55.523	ESP
1190128	Mystic Station	7	0.002, 0.003	131	46	46.690	ESP
1190194	Salem Harbor	4	0.001, 0.001	316	24	1.000	ESP
1200067	Cleary Flood	8	0.003, 0.002	20	5	1.640	
1200067	Cleary Flood	9			10	3.930	
1200067	Cleary Flood	9A			19		
1197654	Wheelabrator - Saugus	1	0.000, 0.000		0	4.282	
1197654	Wheelabrator - Saugus	2			0	0.845	

Facilities with De Minimis Impacts on Visibility

Massachusetts BART-eligible sources with de minimis impacts on visibility include Braintree Electric, Harvard University – Blackstone, Mirant – Kendall, New Boston, Eastman Gelatin, Solutia and Trigen - Kneeland. Collectively, these seven BART facilities emitted 30 tons of PM10 that diminished visibility in New England Class I areas by 0.002 - 0.004 ddv in 2002.

MassDEP has determined that the visibility improvement that would be achieved by the installation of BART controls at these sources does not justify the cost of installation of such controls. This is consistent with data from MANE-VU, documented in Appendix R in which the entire MANE-VU population of the sources with a de minimis visibility impact (i.e., <0.1 dv) was modeled together to examine their cumulative impacts on each Class I site. The result showed that the maximum 24-hour impact at any Class I area of all modeled sources with individual impacts below 0.1 dv was only a 0.35 dv change relative to the estimated best days' natural conditions at Acadia National Park. This value is below the 0.5 dv impact recommended by EPA for exemption modeling in which a source not only does not need to install BART controls, but does not need to perform a BART five-factor analysis. However, because MANE-VU has decided that once a source is eligible for BART, it is subject to BART, MassDEP has provided a five-factor analysis for these sources (see Section F and Table 4). The minimal impact of these sources on visibility leads to the conclusion that no reasonable weighting could justify additional controls under BART. Thus, BART for Massachusetts sources with de minimis impacts on visibility consists of their existing PM10 emission limits.

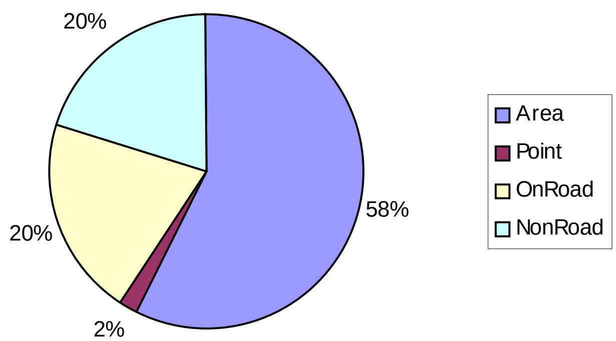
J. BART for VOC Emissions from Petroleum Storage

Massachusetts has three BART-eligible sources that have VOC emissions from petroleum storage: Exxon Mobil – Everett, Global Petroleum – Revere, and Gulf Oil – Chelsea. In addition to their well-known role in ozone formation, VOCs form secondary organic aerosols after condensation and oxidation processes. Thus, VOC emissions are included in the organic carbon section of the emissions inventory. Organic carbon accounts for the second largest share of fine particle mass and particle-related light extinction at northeastern Class I sites (after sulfates). The term "organic carbon" encompasses a large number and variety of chemical compounds that may come directly from emission sources as a part of primary PM or may form in the atmosphere as secondary pollutants. The organic carbon present at Class I sites almost certainly includes a mix of species, including pollutants originating from anthropogenic sources as well as biogenic hydrocarbons emitted by vegetation.

VOC emissions, while significant and potential contributors to visibility impairment, are not well modeled by Lagrangian Dispersion models like CALPUFF. It is therefore difficult to assess the individual contributions of BART-eligible sources to haze at Class I areas. The VOC inventory, however, is dominated by mobile and area sources with only a small fraction of VOC emissions from point sources (2%) as can be seen in

Figure 1 below (from Appendix A, Contribution Assessment).

Figure 1: 2002 VOC Inventory for Massachusetts



MassDEP is continuing to evaluate control technologies for reducing VOC emissions from petroleum storage at facilities statewide and is in the process of developing a regulation proposing more stringent VOC emission limits for petroleum storage facilities. However, no further controls at Exxon Mobil – Everett and Global Petroleum – Revere will be required at this time to satisfy BART, given the minor impact of VOC point sources on regional haze. Gulf Oil – Chelsea has recently agreed to reduce its VOC emissions potential from 10 milligrams/liter (mg/L) to 2 mg/L through use of a negative pressure/capture system and an improved carbon absorption system to gain approval for expansion. These reductions are expected to occur by January 1, 2010, and will be sufficient to satisfy BART requirements.